Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109

Proposed
Regulation 12, Rule 11:
Flare Monitoring at Petroleum Refineries

Draft Staff Report

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Prepared by:

Alex Ezersky
Compliance and Enforcement Division

Bill Guy
Planning and Research Division

TABLE OF CONTENTS

FIGURES

TABLES

EXECUTIVE SUMMARY

Proposed District Regulation 12, Rule 11: Flare Monitoring at Petroleum Refineries is intended to implement control measure SS-15 from the Bay Area 2001 Ozone Attainment Plan. This new rule would require refineries to monitor the volume and composition of gases burned in refinery flares, to calculate flare emissions based on this data, to determine the reasons for flaring, to report all of this information to the District, and to provide video monitoring of flares. The rule will lead to much more accurate estimates of flare emissions, will allow the District to refine its emission inventory for flaring, and will provide information that is likely to lead to reductions in flaring.

Flares are primarily intended as safety and pollution control devices. They burn gases that cannot be used by the refinery and prevent their direct release to the atmosphere. The proposed rule would require the monitoring of these gases. The primary parameters to be monitored are vent gas flow to the flare and vent gas composition.

For monitoring of the volume of gas directed to flares, the rule establishes range and accuracy requirements that, at present, can be met only by ultrasonic flow monitors. These monitors are called time-of-flight (TOF) ultrasonic monitors. They determine flow velocity by measuring the time required for ultrasonic waves to travel in the flare gas from an "upstream" probe to a "downstream" probe and by comparing the time to that required for the slower "upstream" trip. This technology is the best available technology for measuring gas flow for flares. Two of the Bay Area refineries already have older ultrasonic monitors, but the rule would require all of the refineries to install newer, more sophisticated, and more accurate monitors.

For monitoring of flare gas composition, the rule allows two primary options: (1) collection of samples for subsequent lab analysis, or (2) use of continuous analyzers that sample gas and analyze it automatically. For the first option, samples can be collected either manually or with an auto-sampler. For the second option, several continuous analyzer technologies are available: flame ionization detectors (FID), non-dispersive infrared (NDIR) spectrophotometry, and gas chromatography (GC). These methods are widely used by industry and by regulators, but have never been used on flare headers. The rule establishes appropriate methods and procedures for each technology.

The rule allows the two options, sampling and continuous analyzers, because each has advantages and disadvantages that may dictate one over the other for the specific flare in question. Sampling is a proven approach that will, over time, build a large set of data for each flare for which it is used. Yet sampling may require more human attention and result in greater risk to personnel involved in sampling during flaring. Continuous analyzers, though desirable because of the continuous data they can provide, have not yet been used to monitor flare vent gas, which is not as "clean" as most gas streams for which these analyzers are used. Use of continuous analyzers will require sample conditioning equipment that may be difficult to design and may require considerable maintenance (thus perhaps offering no advantage over sampling from a worker safety perspective). The rule represents a compromise, allowing a method that is known to work (sampling) while encouraging a method that the District would like to see proven in practice (continuous analyzers). This ensures that the rule will work and avoids the risk of rule failure that would come from mandating only continuous analyzers and the missed opportunity that might come from mandating only sampling. District staff expect that the result may be the use of continuous analyzers on some flares and sampling on others. Either approach will provide so much data that any uncertainty about flare gas composition will disappear.

The proposed rule requires monitoring data to be submitted to the District in a monthly report that is due within 30 days after the end of each month. The report must include flow data, composition data, emissions estimates, descriptions of all flaring activity, and information on any downtime for the monitors. The rule also requires a semi-annual report comparing flow monitor data for a period of time with a set of data for the same period derived by other methods. The comparison data can come from methods approved by the monitor manufacturer, from flow velocity measurements using tracer gases, from precisely known or calculated flows, from flow measurements with pitot tubes, or from data derived from other methods approved by the District.

The proposed rule also requires video monitoring of flares. The flare image is required to be recorded, and the recording for each 24-hour period is required to be retained until 15 days after submittal of the monthly report. This will allow the District to examine flare imagery to help explain any flaring, to respond to any community concerns or complaints, and to ensure that monitor data corresponds with the images.

The rule requirements would be imposed in steps that are based upon the District's determination about the length of time required to install the necessary equipment. All refineries would have to start taking daily composition samples within 2 months (some are already doing so). Within 6 months, each refinery will have to have continuous flow monitors in place. In 9 months, each refinery will be required to monitor composition at more frequent intervals through sampling or continuously with continuous analyzers.

The proposed rule would apply to the 25 flares located at the five Bay Area refineries: ChevronTexaco in Richmond (9 flares), ConocoPhillips in Rodeo (2 flares), Valero in Benicia (3 flares), Tesoro in Avon (6 flares), and Shell in Martinez (5 flares). Two of the twenty-five are not in service. All of the flares in service are currently monitored for some parameter, typically flow or vent gas heating value. The proposed rule would require that all of the refineries upgrade their current monitoring equipment, but the new equipment necessary and the costs involved would vary greatly, depending upon the sophistication of the currently-installed equipment. The District has estimated a range of costs for a refinery based on costs for the various options allowed under the proposed rule. For a refinery with two flares and ultrasonic monitors already in place, costs could be relatively modest. For a refinery with a large number of flares and little or no existing monitoring equipment, costs could be considerable.

In developing this rule, the District relied on information and data gathered during the District's flare further study effort. In August 2002, District staff held a workshop in

Martinez to discuss basic rule concepts. It began developing a draft rule in late 2002, and in March shared preliminary drafts with representatives from the five Bay Area refineries, the Western States Petroleum Association (WSPA), and Communities for a Better Environment (CBE). In late March and early April, District staff held three community meetings to discuss detailed rule concepts. The meetings were held in Richmond, Martinez, and Rodeo. Rule drafts have also been shared with ARB and EPA.

Pursuant to the California Environmental Quality Act (CEQA), the District prepared an initial study to determine the potential environmental impacts of proposed Regulation 12, Rule 11. The study identified the construction work required to install monitors as a source of potential environmental impacts. However, because of the safety requirements that govern this type of work, the regularity with which similar hot work is conducted in refineries, and the consequent familiarity with and preparedness for this type of work on the part of refinery workers and contractors, the study concluded that the proposed rule would not result in any significant environmental impacts.

BACKGROUND

Flares provide a safety and emission control mechanism for refinery blowdown systems. Blowdown systems collect and separate both liquid and gaseous discharges from various refinery process units and equipment. The systems generally recover liquids and send gases to the fuel gas system for use in refinery combustion. However, when the heating value of the gas stream is insufficient, when the stream is intermittent, or when the stream exceeds what is necessary to satisfy refinery combustion needs, flares combust these gases and prevent their direct release to the atmosphere. Flares are designed to handle large fluctuations in the flow rate and hydrocarbon content of gases.

Flares and Similar Devices

A number of different devices may be called flares. A flare, as defined in the proposed rule, is a combustion device that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air surrounding the flame. The term is most commonly applied to the open air flare. It is also commonly applied to ground flares, which are located at ground level and typically have an enclosure around the open flame. The term "enclosed flare" may also be applied to this type of flare, regardless whether it is located at ground level. Flares, whether "open air," "ground," or "enclosed," rely on surrounding air for combustion and do not have any mechanism for control of this combustion air.

The term "thermal oxidizer" is sometimes used as a broad term to apply to many types of devices that oxidize combustible gases, including flares. However, the term is more properly applied to enclosed devices that, unlike flares, control the mixing of combustion air and fuel. As defined in the proposed rule, a thermal oxidizer is an enclosed or partially enclosed combustion device that is used to oxidize combustible gases and that generally comes with controls for combustion temperature and often with controls for air/fuel mixture.

In general, flares are used to control units and operations from which gas flows may be intermittent and may range from very low flows to very high flows. They are accepted as the most reliable way to ensure that the potentially enormous flows that may result from an upset or shutdown of a large refinery unit, a large block of units, or an entire refinery can be controlled.

Thermal oxidizers are generally used to control emissions from sources or operations for which flows are lower and more stable. These sources include wastewater systems, loading racks, storage vessels, pumps or compressors, and some relief systems on small process units. Because of the greater control over combustion afforded by temperature and mixture controls, thermal oxidizers typically have very high combustion efficiency.

Flare Design and Operation

The open air flare is the predominant design type in the Bay Area. These flares are designed to handle large fluctuations in the flow rate and hydrocarbon content of gases. They are used to prevent releases of uncombusted materials generated during maintenance activities, emergency events such as power and equipment failures, and to a lesser extent as a control device for materials that can not be recovered.

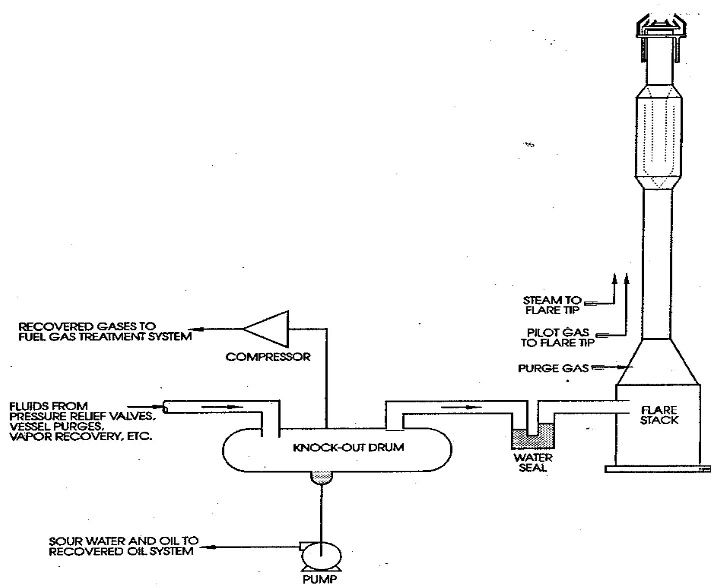

Figure 1. Typical Flare System

The diagram above illustrates a typical general service flare system. The system is a component of the refinery blowdown system. The blowdown system is designed to collect gases and liquids released throughout the refinery and direct them to the refinery recovery system or, when there is insufficient capacity to recover them, to a flare. These gases and liquids may be released for many different reasons. They may be normal byproducts of a process unit or vessel, they may result from an upset in a process unit, or they may come from refinery process units during startup and shutdown when the balance between gas generation and the combustion of that gas for process heat is disrupted.

The blowdown system delivers gases and liquids to a knock-out drum that captures liquids and directs them to the oil recovery stream. The refinery flare gas compressors then direct gases to the fuel gas system. The extent to which these gases can be captured depends upon the capacity of the compressors. A refinery in good balance should be able to capture most of the gases delivered to the blowdown system during normal operations and use them to heat process units. This is not the case if a refinery has insufficient compressor capacity or when there is an upset or accident, and the volume of gases is too great for the compressors to handle.

Emissions from Flares

Flares produce air pollutants through two primary mechanisms. The first mechanism is incomplete combustion. Like all combustion devices, flares do not combust all of the fuel directed to them. Combustion efficiency is the extent to which the oxidation reactions that occur in combustion are complete reactions converting the gases entering the flare into fully oxidized combustion products. Combustion efficiency may be stated in terms of the extent to which all gases entering the flare are combusted, typically called "overall combustion efficiency" or simply "combustion efficiency", or it may be stated as the efficiency of combustion for some constituent of the flare gas as, for example, "hydrocarbon destruction efficiency."

The second mechanism of pollutant generation is through the oxidation of flare gases to form other pollutants. As an example, the gases that are burned in flares typically contain sulfur in varying amounts. Combustion oxidizes these sulfur compounds to form sulfur dioxide, a pollutant. In addition, combustion also produces relatively minor amounts of nitrogen oxides through oxidation of the nitrogen in flare gas or atmospheric nitrogen in combustion air.

Unlike internal combustion devices like engines and turbines, flares combust fuel in the open air, and combustion products are not contained and emitted through a stack, a duct, or an exhaust pipe. As a result, emission measurement is difficult.

Studies can be conducted on small flares under a hood or in a wind tunnel where all combustion products can be captured. Any results for these small flares must be adjusted with scaling factors if they are to be applied to full-size flares. For full-size operating industrial flares, which may have a diameter of four feet or more and a stack height of 200 feet or more, all combustion products cannot be captured and measured. To study emissions from these flares, emissions can be sampled with downwind test probes attached to the stack, a tower, or a crane. Emissions can also be studied using remote sensing technologies like open-path Fourier transform infrared technology (FTIR) or differential absorption lidar (DIAL). In applying the results of any particular study to a specific flare or flare type, it is important to note any differences in flare design and construction. For example, some flares are simply open pipes, while others, like most refinery flares, have flare tips that are engineered to promote mixing. In addition, studies suggest that composition and BTU content of gas burned, gas flow rates, flare operating conditions, and environmental factors like wind speed may affect, to varying extents, the efficiency of flare combustion.

Since the early 1980's, flares have generally been thought to have a combustion efficiency greater than or equal to 98% under most operating conditions. This view is the result of research jointly conducted by EPA, the Chemical Manufacturers Association, and a flare manufacturer, the John Zinc Company, in the early 1980's. The research was conducted on various relatively small flares (1.5 to 12 inch tips) using propylene gas both alone and blended with nitrogen to simulate typical mixtures found when process vessels are purged with nitrogen. Flow rates were varied over a range encountered in normal operations, and tests were conducted with and without steam assist and air assist. Combustion products were sampled using test probes around the flare. Measured efficiencies ranged from 98.5% to 99.75%.

Recent research on flares in the field using remote sensing also supports the conventional view of high efficiency. A study of 3 large (42 and 48 inch) refinery flares conducted by British Petroleum Oil Technology, Statoil, and Spectrasyne, a British manufacturer and operator of DIAL remote sensing equipment, suggested flare efficiencies greater than 98% at wind speeds up to 38 miles per hour. (Boden). Similar remote sensing results were obtained for solution gas flares and gas plant flares of unspecified size in Nigerian oil fields (Ozumba, et al.).

Some research suggests reduced combustion efficiency for particular types of flares or operating conditions. Much of this research has been carried out by the Alberta Research Council on solution gas flares in the Alberta oil and gas fields. These flares are simple open pipe flares. In a series of papers, Canadian researchers have developed a theoretical model to predict flame size and flare efficiency (Leahey 1985, 1996, 2001). The model has been shown to accurately predict flame size for sour gas solution gas flares, for small laboratory flares and for a large emergency flare (Leahey 2001). Measured and predicted efficiencies for very small oil field solution gas flares were both approximately 70% (Leahey 2001). However, another study found an efficiency of 95% for a large carbon monoxide flare for which the model would have predicted an efficiency of 30% (Blackwood). Whether the Canadian research is relevant to refinery flares is unresolved. Nevertheless, all of this research suggests that efficiency may be lower than 98% for low-BTU gases, high stack exit velocities, and high wind speeds.

The question of flare combustion efficiency is one of the flaring issues being explored by the Technical Committee of the BAAQMD Advisory Council. On April 1, 2003, District staff and representatives from Bay Area refineries made presentations to the Committee on various flare issues, including combustion efficiency. The Committee has indicated that it intends to examine the efficiency issue and may invite experts to appear before it.

Most of the flares at the Bay Area refineries are large flares with flare tips designed to promote mixing and efficient combustion. Some of these flares are subject to federal standards or permit conditions that require them to meet an efficiency of 98%. Because of these requirements and because the available evidence to date suggests that the combustion efficiency of refinery flares under normal operating conditions is approximately 98%, the proposed rule requires that emission calculations used to prepare monthly reports assume an efficiency of 98% except for flares that burn flexi-coker gas, a low-BTU gas. In assessing emissions, the District may use other combustion efficiencies where appropriate.

Bay Area Flares and Existing Monitoring Equipment

There are 25 flares at the five Bay Area refineries. Two of these flares are not in operation. All of these flares in service have some existing monitoring equipment to monitor one or more of the following parameters: (1) hydrogen sulfide content of the fuel gas used for the pilot, (2) status of the pilot light, (3) flame appearance to insure a smokeless operation, (4) heating value of the gases, (5) compliance with limits on the amount of material processed at the flare, (6) quantity of fuel gas, and (7) total reduced sulfur content. Table 2 on the following page lists flares that would be subject to the proposed rule. For each flare, the table lists the existing monitoring equipment and the reason or reasons that the equipment is installed.

Table 1: Existing Flare Monitoring

Site & Source #	Service	Parameter Monitored	Monitor Type	Basis[1]
Chevron				
6006	LSFO Low Level Flare		N/A	Disconnected
6010	LSFO High Level Flare	Pilot & purge gas, btu & HHV	Flow transmitter & chart	PC
6012	South Isomax	Pilot gas, btu & HHV	Rotameter	PC
6013	North Isomax	Purge gas, btu & HHV	Field meter	PC
6015	D&R Flare	Pilot & purge gas, btu & HHV	Flow transmitter & chart	PC, NSPS
6016	FCC Flare	Pilot & purge gas, btu & HHV	Flow transmitter & chart	PC
6017	SRU Flare	Pilot & purge gas, btu & HHV	Flow transmitter & chart	PC
6019	Alky Flare	Pilot & purge gas, btu & HHV	Flow transmitter & chart	PC
6039	Lube Flare (RLOP)	Pilot & purge, btu & HHV	Rotameter	PC
Shell				
1471	LOP Auxiliary Flare	Flow, molecular wt.	Ultrasonic	PC
1472	LOP Main Flare	Flow, molecular wt.	N/A	Blinded Off
1771	FXG Flare	H_2S, flow	Venturi	PC, NSPS
1772	HC Flare	H_2S, flow	Orifice	PC, NSPS
4201	Delayed Coking Flare	Molecular wt., sulfur, btu/scf, fuel flow		PC, NSPS
ConocoPhillips				
297	C-1 Flare	Flow	Ultrasonic, anemometer	PC, NSPS
398	C-602 Flare	Flow	Ultrasonic	PC, NSPS
Tesoro				
854	East Air Flare	Flow, sulfur	Ultrasonic	PC, NSPS
944	North Coker Flare	Flow, sulfur	Ultrasonic	PC, NSPS
945	South Coker Flare	Flow, sulfur	Ultrasonic	PC, NSPS
992	Emergency Flare	Flow, sulfur	Ultrasonic	PC, NSPS
1012	West Air Flare	Flow, sulfur	Ultrasonic	PC, NSPS
1013	Ammonia Flare	Flow		
Valero				
16	Acid Gas Flare	Purge flow	Orifice plate	PC
18	South Flare	Oil, flow, hydrocarbon	Venturi meter, anemometer	EB
19	North Flare	Oil, flow, hydrocarbon, H_2S	Venturi meter, anemometer	EB, NSPS

[1] PC - Permit Condition
EB - Energy Balance
NSPS - Federal New Source Performance Standards for flares used as a control device

As shown in the table, a variety of technologies are used to quantify the volume of gases combusted. Each technology has advantages and limitations. Some of these have been identified by EPA in their Compliance Assurance Monitoring (CAM) Technical Guidance Document and are summarized in Table 3 on the following pages.

Table 2: Comparison of Flow Measurement Devices

Type of Flow Meter	Type of Measurement	Liquid, Gas, or Both	Applicable Pipe Diameter	Applicable Flow Rate	Straight Pipe Requirements[a]	Net Pressure Loss	Accuracy	Restrictions
Venturi Tube	Volumetric	Both	5 to 120 cm (2 to 48 in.)	Limited to ~ 4:1 flow range	6 to 20 D up 2 to 40 D down	10 to 20% of ΔP depending on β	± 0.75% flow rate w/o calibration	Eliminate swirl and pulsations
Flow nozzle	Volumetric	Both	7.6 to 60 cm (3 to 24 in.)	Limited to ~ 4:1 flow range	6 to 20 D up 2 to 4 D down	30 to 8.5% of ΔP depending on β	± 1.0% flow rate w/o calibration	Eliminate swirl and pulsations
Orifice plate	Volumetric	Both	1.3 to 180 cm (1/2 to 72 in.)	Limited to ~ 4:1 flow range	6 to 20 D up 2 to 4 D down	Slightly more than flow nozzle	± 0.6% flow rate w/o calibration	Eliminate swirl and pulsations
Magnetic	Velocity	Liquid (not petroleum)	0.25 to 250 cm (0.1 to 96 in.)	0.0008 to 9,500 L/min (0.002 to 2,500 gal/min)	None	None	± 1% flow rate	Conductive liquid, not for gas
Nutating disk	Volumetric	Liquid	1.3 to 5 cm (1/2 to 2 in.)	7.5 to 600 L/min (2 to 160 gal/min)	None		± 0.5% flow rate	Household water meter, low maximum flow rate
Oscillating piston	Volumetric	Liquid	1.3 to 5 cm (1/2 to 2 in.)	2.8 to 600 L/min (0.75 to 160 gal/min) Maximum of 4.3 to 480 m^3/hr (150 to 17,000 ft ^{3}/hr)	None		± 0.5% flow rate	Household water meter, low maximum flow rate
Bellows gas	Volumetric	Gas		Maximum of 4.3 top 480 m^3/hr (150 to 17,000 ft^3/hr)	None			Used for commercial and domestic gas service
Lobed impeller	Volumetric	Both	3.8 to 60 cm (1-1/2 to 24 in.)	30 to 68,000 L/min (8 to 18,000 gal/min)	None	Low	± 0.2% flow rate	Best used at high flow rates
Slide-vane rotary	Volumetric	Liquid	Up to 40 cm (Up to 16 in.)		None		± 0.1% to 0.2% flow rate	
Retracting-vane rotary	Volumetric	Liquid	Up to 10 cm (Up to 4 in.)		None		± 0.1% to 0.2% flow rate	
Helical Gear	Volumetric	Liquid	3.8 to 25 cm (1-1/2 to 10 in.)	19 to 15000 L/min (5 to 4,000 gal/min)	None	Low	± 0.1% to 0.2% flow rate	High viscous liquids only
Turbine	Volumetric	Both	0.64 to 60 cm (1/4 to 24 in.)	190,000 L/min (50,000 gal/min) 65 scmm (230,000 scfm)	10 D up 5 D down	34 to 41 kPa @ 6.1 m/sec. (5 to 6 psi @ 20 ft/sec) water flow	± 0.5% flow rate	Straightening vanes. Do not exceed maximum flow
Vortex Shedding	Velocity	Both	2.5 to 30 cm (1 to 12 in.)	0.30 to 6.1 m/sec (1 to 30 ft/sec) 11 to 19,000 L/min (3 to 5,000 gal/min)	10 to 20D up 5 D down	34 to 41 kPa @ 6.1 m/sec (5 to 6 psi @ 20 ft/sec) water flow	± 1% flow rate (liquid) ± 2% flow rate (gas)	Straightening vanes
Vortex Precession	Velocity	Gas	2.5 to 20 cm (1 to 8 in.)	0.30 to 6.1 m/sec (1 to 20 ft/sec)	10 to 20 D up 5 D down	5% more than shedder	± 2% flow rate	Straightening vanes
Fluidic oscillating	Velocity	Liquid	2.5 to 10 cm (1 to 4 in.)	Up to 6.1 m/sec (20 ft/sec)	6 D up 2 D down	34 to 41 kPa @ 6.1 m/sec. 5 to 6 psi @ 20 ft/s water flow	± 1.25 to 2% flow rate	Carefully determine minimum flow rate
TOF ultrasonic	Velocity	Both	> 0.32 cm > 1/8 in.)	Minimum 0.03 m/sec (0.1 ft/sec)	10 to 30 D up 5 to 10 D down	None	± 0.5% to 10% full scale	Need clean fluid

Type of Flow Meter	Type of Measurement	Liquid, Gas, or Both	Applicable Pipe Diameter	Applicable Flow Rate	Straight Pipe Requirements[a]	Net Pressure Loss	Accuracy	Restrictions
Doppler Ultrasonic	Velocity	Liquid	> 0.32 cm (> 1/8 in.)	Minimum 0.15 m/s (0.5 ft/sec); 0.38 L/min (0.1 gal/min)	Yes	None	As low as 1% flow rate	Fluid must have sufficient particles or bubbles
Thermo-anemometer	Velocity (mass)	Gas	> 5 cm (> 2 in.)		8 to 10 D up 3 D down	Very low	± 2% flow rate	Critically positioned probes Highly fluid composition dependent
Colorimetric	Velocity (mass)	Gas	> 5 cm (> 2 in.)		8 to 10 D up 3 D down	Low	± 4% flow rate	
Coriolis mass	Mass flow	Both limited gas	0.16 to 15 cm (1/16 to 6 in.)	Definitive max. + min. flow rate	None	High	± 0.2% to 0.4% flow rate	Pressure drop across flow meter cannot exceed max. system pressure drop
Rotameter	Velocity	Both	1.3 to 10 cm (1/2 to 4 in.)	Up to 750 L/min (200 gal/min for liquid); unlimited for gas	None	Low	± 1 to 2% full scale	Must be mounted vertically

Flow Monitoring Technologies

The following discussions of flow monitoring technologies are taken from EPA's CAM Guidance. Discussion is limited to those technologies most common in the Bay Area refineries.

Orifice Plates and Venturis

Orifice plates can be used to measure fluid flow in pipes with diameters of approximately 1.3 to 180 cm (0.5 to 72 in.). Orifice plates operate on Bernoulli's principle, which says that pressure decreases with increased flow velocity. An orifice plate consists of a square-edged or sharp-edged, thin opening in a metallic plate perpendicular to the flow. The opening is of a predetermined size and shape and is machined to tight tolerances. The flow velocity must increase through the orifice. The result is a higher pressure upstream of the plate and a lower pressure downstream. The pressure differential increases with flow velocity. The pressure readings for an orifice plate are obtained from a pair of pressure taps, one on either side of the plate:

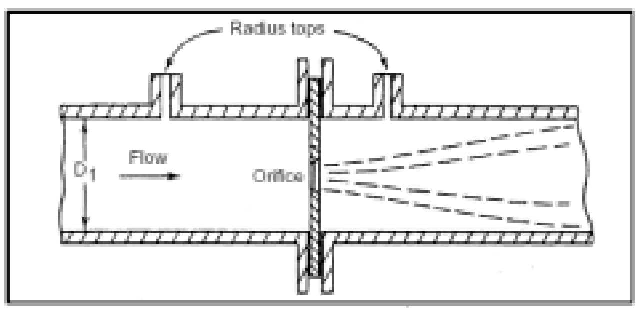

Figure 2. Orifice Plate

Venturi meters operate on the same principle. The pressure differential for a venturi is obtained from two taps: one at the full pipe diameter and one at the throat of the venturi.

Hot Wire Anemometer

The hot wire anemometer (figure 3) works by measuring the current drawn through the hot wire as a result of the cooling effect of the air flow extracting heat from the wire. The instrument maintains the wire at a fixed temperature so that as it is cooled by the air flow the current increases to maintain the temperature of the wire. The core of the anemometer is an exposed hot wire either heated up by a constant current or maintained at a constant temperature (figure 4). In either case, the heat lost to fluid convection is a function of the fluid velocity.

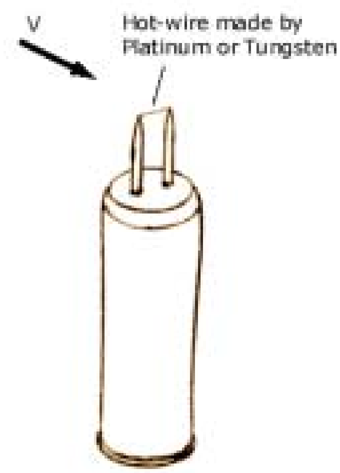

Figure 3. Typical Hot-Wire Anemometer

By measuring the change in wire temperature under constant current or the current required to maintain a constant wire temperature, the heat lost can be obtained. The heat lost can then be converted into a fluid velocity in accordance with convective theory.

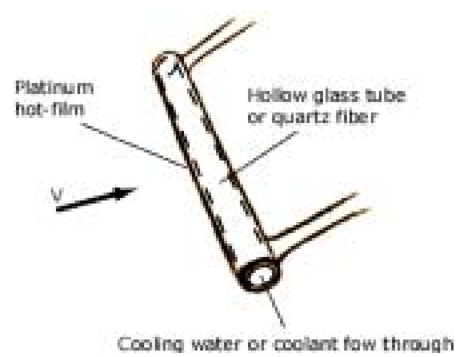

Figure 4. Anemometer Hot Wire

Ultrasonic Flow Meters

Two types of ultrasonic flow meters are available: time-of-flight (TOF) and Doppler. Doppler meters are suitable only for liquids and are not discussed here. In TOF ultrasonic flow meters, sound waves are introduced into the flowing fluid, one wave traveling with the flow and one wave traveling against the flow. The difference in transit time of the waves is proportional to the fluid flow rate, because the sound wave is accelerated when traveling with the flow and slowed when traveling against the flow. If the sound wave velocity of the fluid (speed of sound) is known, the transit distance is known, and time difference is known, then the fluid flow rate can be determined. Time-of-flight ultrasonic flow meters can be classified as one of the following: axial transmission, multi-beam (transverse or longitudinal) contra-propagating, cross beam, sing around, and reflected beam. Figure 5 depicts a TOF ultrasonic flow meter.

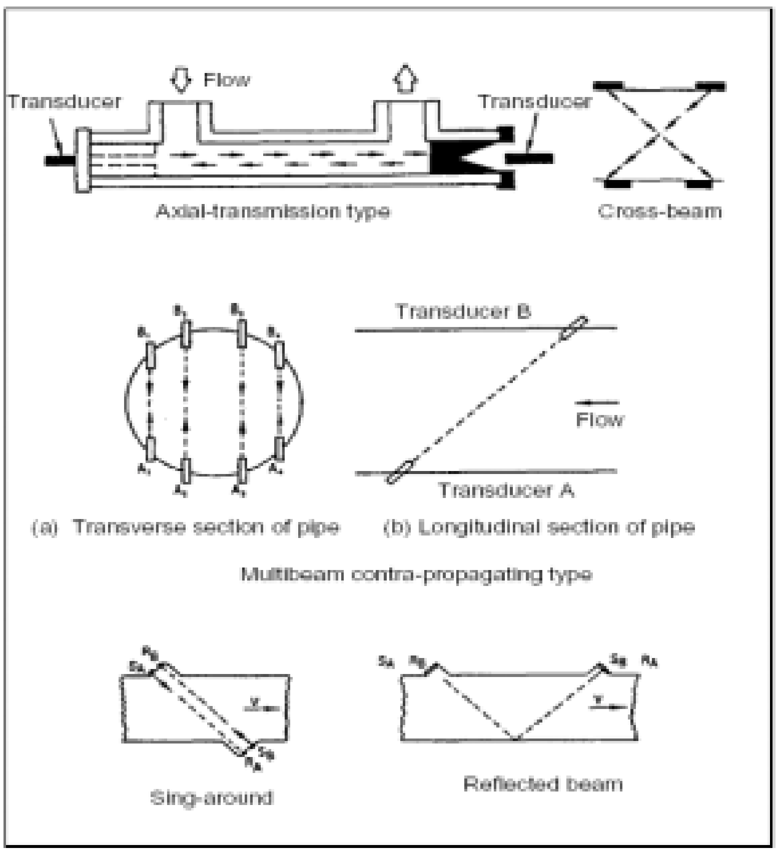

Figure 5. Time of flight ultrasonic flow meter

Ultrasonic flow meters are comprised of the following basic parts: the transducer, receiver, timer, and temperature sensor. Ultrasonic flow meters can be used to measure fluid flow in pipes with a diameter greater than 0.32 cm (0.125 in.) with a minimum flow rate of approximately 0.38 L/min (0.1 gal/min). Time-of-flight ultrasonic flow meters are applicable to liquids and gases flowing at velocities greater than 0.03 m/sec (0.1 ft/sec).

Gas Composition Monitoring

The type of composition monitoring currently in use at a refinery depends upon the applicable regulatory requirements, as shown in Table 2. Regulatory requirements are specified in the District imposed permit conditions or in Federal requirements. The most common requirement is that a flare be monitored for emissions of sulfur oxides to meet New Source Performance Standards for flares used as a control device. For some flares, the District has imposed conditions on flares for purposes of controlling odors or to meet offset requirements. Typically these conditions place limits on the quantity and composition of fuel gas that can be burned, impose design criteria for tip velocity, and specify analytical protocols. Some composition monitoring may be done to meet other needs of the facility. For example, some facilities analyze for composition to "energy balance" the consumption of fuel gas within individual process units. All of the composition monitoring being done at the Bay Area refineries at present is through sampling and subsequent lab analysis.

Composition can also be monitored by continuous analyzers. Several technologies are available: the flame ionization detector (FID), the non-dispersive infrared (NDIR) spectrophotometer, and gas chromatography (GC).

A flame ionization detector (FID) burns sampled gas in a hydrogen flame. Organic compounds produce positive ions, which are collected at an electrode above the flame. The generated current is then measured. The FID is useful for measuring concentrations of organic compounds and is very sensitive and accurate over many orders of magnitude. Because the FID responds to any molecule with a carbon-hydrogen bond, but not at all, or poorly to other compounds, it is not useful for measuring concentrations of hydrogen sulfide or sulfur dioxide.

A non-dispersive infrared (NDIR) spectrophotometer measures the amount of infrared radiation that is absorbed by a sample. Infrared radiation from a hot wire is directed through two parallel cells: a reference cell filled with nitrogen, and a cell through which the sample flows. The gas in the sample cell absorbs an amount of energy proportional to its concentration. This is converted into an electrical output by the detector. The NDIR is used primarily to measure carbon dioxide concentrations, but it may also be used to measure hydrogen sulfide and sulfur dioxide.

A gas chromatograph, or GC, consists of a column, oven, and detector. The column separates the gas sample into its various components. GC columns are available in different sizes, and packing for the columns depends upon the composition of the gas stream to be analyzed. The oven provides a controlled temperature enclosure for the column. The detector has to be chosen based on the type of gases being analyzed. A FID can be used as the detector on a gas chromatograph.

In the gas chromatograph, a sample goes to the column, separates into individual compounds and proceeds through the hydrogen flame ionization detector, generating a response called a chromatogram. The various chemical components contained within the sample travel through the column at different speeds, depending on their respective solubility in or adsorption on the packing material (liquid or solid). The height of the peak on the chromatogram is related to the concentration and the time it takes to go through the column, which helps identify the component.

History of Monitoring

In 1984, Citizens for a Better Environment (CBE) petitioned the California Air Resources Board (CARB) to evaluate the feasibility of continuous emission monitors for refinery flares. CARB determined that no refinery in California accurately monitored flow rates to its flares. Several types of flow meters had been installed on refinery flares, but the instrumentation could only provide relative flow information because gas density varies and gas composition data is necessary to calculate flow accurately. CARB concluded that continuous monitoring of flow rates and composition and remote monitoring of flare plumes would require substantial development before it would be available (CARB). CARB determined that monitoring devices were available for limited applications to identify and record continuously the on/off status of flares. CARB also encouraged local air pollution control districts to adopt rules requiring refineries to install on/off status monitors and collect flare gas composition data so that a suggested control measure for the control of emissions from refinery flares could be developed.

In response to the CARB findings, the District conducted a flare monitoring study in 1988 and 1989 using the tools that were then available (BAAQMD 1990). Instantaneous flow information was obtained using pitot tubes. Composition was analyzed by taking grab samples at the same time that the flow measurement was made. All of the data simply gave the District a series of "snapshot" data. Conclusions had to be extrapolated from this limited data by assuming that it was representative of refinery operations, but there was no way to determine whether this was a valid assumption. Nevertheless, it remained the only flare flow and composition data set available for Bay Area refineries. The data collected was used as a basis for adjustments to the emission inventory used for the Bay Area 2001 Ozone Attainment Plan.

By the 1990's, ultrasonic flow meters were coming to be regarded as a reliable way to measure flare flows. Recognizing that the ultrasonic meters provided a reliable means of monitoring flare gas, the South Coast Air Quality Management District adopted its Rule 1118 requiring refinery flare monitoring. The rule was adopted in 1998, but there were numerous delays, and monitors were finally installed and operational by late 2000.

California Air District Regulations

The following table summarizes existing flare regulations within California.

Table 3: California Flare Monitoring Rules

Regulation	Control/Performance Requirements	Monitoring Requirements	Minimization Plan	Emission Limitations
SCAQMD Rule 1118	None	Gas flow, heating value and sulfur content	No	No
SJVAPCD Rule 4311	Open Air Flares <5psig must meet 40 CFR section 60.18	For flares used during an emergency, record of the duration of flare operation, amount of gas burned, and the nature of the emergency situation.	No	Ground level enclosed flares only
SBAPCD Rule 359	Heating value, exit velocity, automatic ignition system	Presence of a flame	Yes	Sulfur compounds may not exceed 15 grains per 100 cubic feet (239 ppmv) in the Southern Zone of Santa Barbara County or 50 grains per 100 cubic feet (796 ppmv) in the Northern Zone of Santa Barbara County; smokeless

In 1994, the Santa Barbara Air Pollution Control District (SBAPCD) adopted Rule 359, Flares and Thermal Oxidizers. This rule applies to flares and thermal oxidizers used in oil and gas production, petroleum refineries and related sources, natural gas supply and transportation sources, and in distribution petroleum/petroleum products. Rule 359 specifies sulfur content limits for flare gas, technology-based standards for flares and thermal oxidizers, emission limits for nitrogen oxides and reactive organic compounds, and operational limits. The rule also requires plans to minimize use of flares.

In 1998, the South Coast Air Quality Management District adopted Rule 1118 (Emissions from Refinery Flares), which requires refinery flare monitoring. Monitors were installed and operational by late 2000.

In 2002, the San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD) adopted Rule 4311, Flares. This rule requires all open air flares to comply with federal limitations on sulfur in fuel gas. The federal requirement (40 CFR section 60.18) is found in New Source Performance Standards and, in the absence of the SJVUAPCD rule, would apply only to new flares. The rule does not impose extensive monitoring requirements like those in the proposed District rule or in SCAQMD Rule 1118.

PROPOSED RULE

Proposed Regulation 12, Rule 11 would require refiners to:

- Continuously monitor vent gas flow for each flare;
- Monitor vent gas composition either by (1) taking samples manually or with an auto sampler, or by (2) using continuous analyzers;
- Submit monthly reports that include vent gas flow and composition, pilot and purge gas flow and composition, estimates of hydrocarbon and sulfur emissions, descriptions of all flaring (duration, time, cause, measures to reduce or eliminate), and explanations for any monitor downtime;
- Monitor flare operation by video camera and record and retain recordings of flare images.

These requirements would be imposed in steps that are based upon the District's determination about the length of time required to install the necessary equipment:

- Effective in 60 days, each refinery would be required to begin daily sampling for composition. (Some refiners already have this capability and are reporting this data to the District pursuant to an agreement entered into pursuant to the flare further study effort described in the introduction; others will have to install necessary sampling ports.)

- Effective in 180 days, each refinery will have to have continuous flow monitors in place. This effective data is based upon the expectation that the manufacturer of ultrasonic flow monitors will be able to supply, and the refiners will be able to install, these monitors within this time.

- Effective in 270 days, each refinery will be required to have in place the equipment necessary to monitor composition at more frequent intervals or continuously. If sampling is chosen, the refineries will have to determine how to take more frequent samples, either through installation of auto-samplers or additional staffing, and how to process these samples, either in their own labs or through outside labs. If continuous analyzers are chosen, the refineries will have to design and install sample conditioning trains and analyzers, or arrange to have this work done by outside vendors.

The following sections of the staff report discuss the provisions of the proposed rule in the order in which they appear in the rule.

Exemptions

The exemptions are intended to make it clear that the rule applies to flares and not other types of abatement devices used to control small sources and operations such as storage tanks or loading racks. They also provide a limited exemption for one reporting requirement.

Section 12-11-110 Exemption, Organic Liquid Storage and Distribution

At least one refinery uses a flare to control large butane tanks and at least one refinery uses a flare to control a gasoline loading rack. These flares are used as control devices and control relatively small and relatively clean gas streams. The devices do not have any potential for significant emissions.

Section 12-11-111 Exemption, Marine Loading Terminals

At least one refinery uses a thermal oxidizer to control emissions from its wastewater treatment system. As with the other such devices exempted, the device is solely a control device, and there is no potential for significant emissions.

Section 12-11-113 Exemption, Pumps

Pumps are subject to the District's equipment leak rule, Regulation 8, Rule 18. The rule imposes the most stringent equipment leak limits in California, and one way of complying is by installing containment around a pump seal and directing emissions to an abatement device. One refinery uses a thermal oxidizer to control these emissions, and the exemption is intended to make it clear that the proposed rule does not apply to a thermal oxidizer of this type. Because another refinery has directed fugitive emissions from one or more pumps to the refinery's general blowdown and relief system, additional language makes it clear that the exemption would not apply to exempt a flare that might combust these emissions.

Section 12-11-114 Limited Exemption, Flare Data Reporting

This section is intended to exempt certain flares from reporting (and therefore monitoring) hydrocarbon composition of vent gas. The exempted flares exclusively serve sulfur plants and ammonia plants or exclusively burn flexi-coker gas. Vent gas to these flares contains no hydrocarbons (aside from methane in the case of flexi-coker gas). These flares are still required to monitor flow and sulfur composition.

Definitions

As with all District rules, the proposed flare monitoring rule defines terms used in the rule. There are two things to note about the definitions. First, the terms "flare" and "thermal oxidizer" are defined (Sections 12-11-201 and 208) to make it clear that the rule applies to the flares that are listed in this staff report and not to thermal oxidizers and other abatement devices. Second, the term "vent gas" is defined (Section 12-11-209) to include all gas directed to a flare, excluding steam or air used to aid combustion and excluding pilot and continuous purge gas. This definition in then used in the definition of "flaring" (Section

12-11-202. The result is that "flaring" is any time the flare has a flame other than the pilot flame.

Administrative Requirements

The Administrative Requirements set forth reporting requirements.

Section 12-11-401 Flare Data Reporting Requirements

This section requires a monthly report that must include the following:

- Upon rule adoption, total flow for each day and for the month. The Bay Area refineries currently have various means of determining flow and are reporting this data to the District pursuant to an agreement developed for flare further study measure FS-8. The rule will require continued reporting of this data. After the flow monitors required by Section 12-11-501 are installed, the report would also have to include flow for each hour of the month (ultrasonic flow monitors are capable of providing much greater flow detail than the means currently employed by most of the refineries).

- Hydrocarbon and sulfur content for every vent gas sample, and if continuous analyzers are used, for every hour of the month.

- Type and quantity of pilot gas and purge gas used for each day and for the month. Where these flows are constant because of flare design, the parameters that dictate flow and the resultant flow are sufficient.

- Estimates of total hydrocarbon, non-methane hydrocarbons, and sulfur dioxide emissions for each day and for the month. Emissions from pilot and purge gas would have to be separately noted.

- For any 24-hour period during which more than 1.2 million standard cubic feet of vent gas are flared, a descriptions of the flaring, including time, duration, cause, the source of the vent gas, and any measures taken to reduce or eliminate flaring.

- Flare monitoring downtime and an explanation for each period of downtime.

Section 12-11-402 Flow Verification Report

This section requires a semi-annual report on alternative means of determining flow to serve as a check on the data being provided by the flow monitors. Ultrasonic flow monitors provide the most accurate and reliable means available to determine flare header flow. No alternative method can provide similar precision. If the ultrasonic monitor has been installed and calibrated properly, the data should be reliable. In one case during the flare study being conducted by the District, a refinery submitted data from an ultrasonic monitor and mistakenly assumed that the ultrasonic monitor range setting was 10 times the actual set range (for example, a value was assumed to be 5 million when it was actually 500,000). The required semi-annual report will ensure that such errors are caught through a comparison of other data to the reported data. There are several alternative ways of determining flow that can be used as a "reality check" on the monitor. These alternatives are listed in Section 12-11-602 (see the discussion of that section for an explanation of each alternative). If a semi-annual report suggests that there may be a problem with a monitor, the District will be able to investigate further to determine whether the monitor still meets the requirements of Section 12-11-501 (requiring the monitor to accurately measure flow rate and molecular weight).

Monitoring and Records

The Monitoring and Records requirements are the heart of the rule and impose the various monitoring requirements.

Section 12-11-501 Vent Gas Flow Monitoring

This section requires continuous monitoring of vent gas flow. The section specifies that the device used to do this monitoring (1) must be capable of detecting a minimum flow velocity of 0.1 feet per second, (2) must continuously measure the range of flow rates corresponding to flow velocities from 0.5 to 250 feet per second, (3) must continuously measure molecular weight, and (4) must be installed on the flare header in a location that ensures that it measures all flow. These requirements can, at present, be met only by a time of flight ultrasonic monitor. The available monitors have a minimum level of detection of 0.1 feet per second, but the manufacturer guarantees accuracy only in the range from 0.5 feet per second to 275 feet per second. In addition, users of these meters and the manufacturer suggest that these flow meters are generally less accurate for measuring gas flow in a flare header when velocity drops below 1 foot per second.

Section 12-11-502 Vent Gas Composition Monitoring

This section requires composition monitoring of vent gas. At present, some of the Bay Area refineries are taking daily samples of vent gas for lab analysis. Within 60 days after rule adoption and until more stringent requirements in the section take effect, all Bay Area refineries are required to take and analyze daily samples (Section 12-11-502.2). Effective nine months after rule adoption, refiners will have two primary options: (1) sampling and subsequent lab analysis, or (2) the use of continuous analyzers. These two options are discussed below.

General Requirements

Section 12-11-502.1 specifies requirements that apply to all composition monitoring. Vent gas monitored for composition must be taken from a location that is representative of vent gas composition. Where flares share a common header, a sample from the header is sufficient for all flares served by the header. All composition monitoring must provide a means for the District to take samples to verify the composition analyses required by the rule.

Sampling

Sampling is proposed as one option (Section 12-11-502.3.1) because the technology is proven, is robust, and is already in widespread use. A primary advantage of sampling is that vent gas samples will not require a complex sample conditioning train such as those required for continuous analyzers. Some refineries in Southern California are using auto-samplers to take vent gas samples, and both the manual sampling and auto-sampling are proven in practice. The disadvantage of manual sampling, is that great care must be taken to ensure the safety of refinery workers involved in sampling. In some cases, the available sampling locations may have potential to expose workers to dangerous heat if the vent gas flow rate is high. In addition, manual sampling and auto sampling do not give continuous results. (Note that continuous analyzers, despite the name, do not give continuous results but instead have a cycle time that may be longer than 15 minutes - see discussion below.)

For the sampling option, the rule specifies a minimum sampling frequency of one sample per day. However, during flaring, the sampling frequency increases. The proposed rule states that if 50,000 standard cubic feet of gas has been flared in any consecutive 60 minute period, a sample must be taken within 15 minutes if an auto-sampler is used or within 30 minutes if manual sampling is used. Sampling must continue at 3 hour intervals until flaring ends. If flaring ends before a sample is required, no sample need be taken.

The trigger of 50,000 standard cubic feet was chosen for several reasons. First, as noted above in the discussion of flow monitoring, ultrasonic flow meters are not as accurate at flow velocities below 1 foot per second. The volumetric flow rate for a given flow velocity depends upon the size of the flare header. The table below lists volumetric flow for a flow velocity of 1 foot per second in various sized flare headers.

Table 4: Flow as a Function of Header Size and Velocity

Volumetric Flow Rate for Given Flow Velocities (ft^3/hr)				
Flow Velocity (feet/sec.)	Diameter of Flare Header (inches)			
	24"	30"	42"	48"
1.0	11,310	17,671	34,636	45,239

Because most of the refineries have one or more large (42 inch or 48 inch) flare headers, using flow above 50,000 standard cubic feet per hour as a trigger ensures that flow velocity is within the more reliable range of the flow meters. With a lower trigger, flow may be indicated where none exists (i.e., a false positive flow). Under such circumstances, samples would not represent actual vent gas but would instead represent still gas in the header and could bias results.

A second reason for choosing the proposed trigger is that an analysis of data collected during the District's flare study shows that use of the proposed trigger would capture most of the flaring events of significance. Even if some events are missed, sampling will quickly build up such an extensive collection of data that little uncertainty will remain about the composition of flare gas.

A third reason for choosing this trigger is that the data loggers used to record flare flow can be easily programmed to sum total vent gas volume flared for the current minute and the prior 59 minutes. This will provide a clear signal for triggering sampling and can be easily enforced.

A fourth reason for choosing the proposed trigger is that alternative forms appear to be more problematic. One alternative trigger that would still rely on the ultrasonic flow meter might be a sustained flow velocity exceeding 1 foot per second over some period of time. The disadvantage is that the sampling trigger would then vary with header size, which seems inequitable. In a small header the flow volume would be relatively inconsequential while significant in a large header. Use of a trigger other than the ultrasonic flow meter was also considered. A visual trigger tied to video monitor images could be used but would be subjective and unenforceable. Use of a trigger based upon flare header pressures that exceed the flare water seal pressure for some period of time would require instrumentation of water seals, and there is little District or industry experience with this data and its correlation to flow.

Continuous Analyzers

The other option for determining vent gas composition is the use of continuous analyzers pursuant to Sections 12-11-502.3.2 and 502.3.3. Several technologies are available: (1) flame ionization detectors (FID), (2) non dispersive infrared (NDIR), and (3) gas chromatography. These technologies were described above under "Background."

Continuous analyzers are widely used to monitor gas composition in the chemical and petroleum industry. However, District staff have been unable to identify any refinery in California or Texas using a continuous analyzer to monitor flare vent gas composition. One of the difficulties of monitoring vent gas is that is can include water, oil, rust and other particles, a very wide range of organic compounds, and high sulfur levels. In general, continuous analyzers need to be carefully tailored to a relatively predictable gas stream. In addition, samples need to be carefully conditioned to remove water and particles. Use of continuous analyzers will therefore require design and installation of a sample conditioning train. There is no off-the-shelf system available for this service. While District staff believe that such a system can be made to work, the technological challenges are not fully known. Until these systems are designed and installed, the maintenance needs for such a system are unknown. Because of the nature of the vent gas stream, it seems likely that these sample trains may require more maintenance than those in more conventional service.

Rationale for Options

The rule allows the two options, sampling and continuous analyzers, because each has advantages and disadvantages that may dictate one over the other for the specific flare in question. Sampling is a proven approach that will, over time, build a large set of data for each flare for which it is used. Yet sampling may require more human attention and result in greater risk to personnel involved in sampling during flaring. Continuous analyzers, though desirable because of the continuous data they can provide, have not yet been proven as a technology to monitor flare vent gas, which is not as "clean" as most gas streams for which these analyzers are used. Use of continuous analyzers will require sample conditioning equipment that may be difficult to design and may require considerable maintenance (thus perhaps offering no advantage over sampling from a human risk perspective). The rule represents a compromise, allowing a method that is known to work (sampling) while encouraging a method that the District would like to see proven in practice (continuous analyzers). This ensures that the rule will work and avoids the risk of rule failure that would come from mandating only continuous analyzers and the missed opportunity that might come from mandating only sampling. District staff expects that the result may be the use of continuous analyzers on some flares and sampling on others. Either approach will provide so much data that any uncertainty about flare gas composition will disappear.

Section 12-11-503 Pilot Monitoring

This section requires each pilot to have a properly functioning ignition system. Most flares have pilot lights and most have an electric arc backup in case the pilot is lost.

Section 12-11-504 Pilot and Purge Gas Monitoring

This section requires monitoring of pilot and purge gas either by a flow measuring device or by the monitoring of other parameters. Several of the refineries use no purge gas, and volumetric flow of pilot gas is constant and dictated by pilot design. Under these circumstances, the monthly report can simply state the parameters that dictate flow and repeat the flow data each month (see discussion of Section 12-11- 401).

Section 12-11-505 Recordkeeping Requirements

Pursuant to this section, monitoring records, except for video monitoring, must be kept for 5 years. The section repeats existing requirements contained in federal law for Title V facilities.

Section 12-11-506 General Monitoring Requirements

General monitoring requirements that apply to all monitors are included in this section. The section restricts hours of monitor inoperation and requires reporting when monitors go out of service. Monitors are allowed 15 consecutive days of inoperation, with proof of expeditious repair required after the 15 days and with a limit of 30 days total in one year.

During periods when monitors are out of service, flows must be calculated and composition must be determined by sampling. Monitors are required to be maintained and calibrated in accordance with manufacturer's requirements. Finally, the section specifies that the electronic data loggers used to record data must be capable of one-minute averages and must record flow data as one-minute averages. Continuous composition analyzers do not produce one-minute averages, as the cycle for such an analyzer may take 15 minutes or more.

Section 12-11-507 Video Monitoring

This section requires the installation within 90 days of recording equipment for flares currently equipped with video monitoring equipment. Effective in 6 months, video monitors and recording equipment must be installed on each flare that currently lacks video monitoring equipment and that has a significant release (1.2 million standard cubic feet of vent gas in 24-hour period) as measured by the ultrasonic flow monitors.

The video monitoring requirements are intended to provide a backup to the extensive data that will be available after the rule's other monitoring requirements go into effect. Community members originally asked for video monitoring so that the District would have the means to verify complaints about flaring. In the past, flaring complaints occasionally came to the District on weekends or at other times when a District inspector was unable to verify the complaint. In the past, however, inspectors did not have the flow and composition data that will now routinely be available. With the proposed rule, video data will be redundant, but the recordings will provide an additional check on flaring.

At the District's August 2002 conceptual workshop for the proposed rule, community members asked for video monitoring with retention of images for a period sufficient to allow verification. The District's original proposal was to require recording of images and retention of the images for 72 hours. At community meetings, many participants requested retention for a greater length of time. The proposed rule therefore requires retention of the images recorded during a particular month until 15 days after submission of the flaring report for that month. This requirement ensures that images will be available to answer questions raised by neighbors or by District staff after reviewing the report.

One participant in the August 2002 conceptual workshop also suggested requiring flare operators to put flare images on the internet. The proposed rule does not require posting of images on the internet. There are four reasons why such a requirement has not been included. First, as noted, the images are redundant to and less reliable than other data that the rule will make available. Second, making an image available to an individual computer user involves a chain of technology, and much of that technology is beyond the control of the flare operator, making such a requirement unenforceable. For example, a refinery has no control over internet service providers, network servers and connections, and internet traffic, and therefore no means to prevent any potential disruption of service that might occur in these areas. In addition, the flare operator has no control over the individual computer user's connection to the internet, computer hardware, computer software, and settings and therefore no means to address problems that may arise in these areas.

The third reason the proposed rule does not require internet posting of images is that it has the potential to require a substantial investment of District staff time in responding to questions and diagnosing problems related to the images. To those who are unfamiliar with flares and do not understand that they will have to continue to be used during upsets and startups and shutdowns to prevent direct releases to the atmosphere, the images may cause unnecessary concern. The fourth reason is that posting the images is simply unnecessary for those who have expressed the concern because they live near the refineries and can see the flares with their own eyes. For these neighbors, the proposed rule ensures that images are recorded if questions ever arise about what they have seen.

Manual of Procedures

The Manual of Procedures provisions specify test methods to be used to carry out the monitoring required by the rule.

Section 12-11-601 Testing, Sampling, and Analytical Methods

This section lists the methods that are allowed for the various approaches to composition monitoring. Section 12-11-601.1 specifies methods to be used for laboratory analysis of samples taken manually or with an auto-sampler. Section 12-11-601.2 specifies methods to be used with flame ionization detectors or non-dispersive infrared spectrophotometry. Section 12-11-601.3 specifies methods for gas chromatography. For gas chromatography, although equipment may be capable of completing cycles in 15 minutes, the allowed sampling frequency is 30 minutes, both because some refiners may want to analyze for additional compounds beyond those required by the rule, which increases the cycle time, or because some may want to use one gas chromatograph to analyze samples from more than one flare header.

Section 12-11-602 Flow Verification Test Methods

Section 12-11-402 requires a semi-annual flow verification for the flow monitors required by the rule. As noted in the discussion of that section, this requirement simply provides a check on the flow meters. Section 12-11-602 specifies 6 methods that can be used to measure or estimate flow for a particular period of time. Pursuant to Section 402, the measure or estimate will then be compared to flow monitor data for the same period. If there is a difference between the data produced by the monitor and that produced by the verification method, it is not possible to know whether the error lies with the meter or with alternative. However, because of the inherent precision of properly calibrated ultrasonic flow meters, minor differences between the flow meter data and the verification data can be presumed to result from imprecision in the verification method. The verification is primarily intended to flag any major differences for further investigation. The verification would catch, for example, any error in the range setting for the ultrasonic flow meter (see discussion under Section 12-11-402). If there is a reason to suspect a problem in the flow meter, a flow meter can be removed and bench tested with controlled flows.

Sections 12-11-602.1 and 602.2 allow pitot tube traverses as a check on flow and specify District and EPA methods respectively for conducting these traverses. These methods involve inserting a pitot tube into a port in a flare header and measuring flow. Though the methods have been included, they are not likely to be used very often because of the risks involved with inserting probes into a live flare header.

Section 12-11-602.3 would allow the use of flow monitors or process monitors that can provide comparison data on a vent stream that is being directed past the ultrasonic flow meter.

Section 12-11-602.4 would allow the use of any method recommended by the manufacturer of the ultrasonic flow meter.

Section 12-11-602.5 would allow the use of a tracer gas to determine flow. A tracer gas can be introduced into a flare header through a port upstream of a second port at which vent gas is sampled for presence of the tracer gas. By timing how long it takes the tracer gas to move from the port where it is introduced to the port where it is detected, flow velocity can be determined.

Section 12-11-602.6 would allow the use of engineering calculations to verify flow meter readings. This is particularly useful when the only flow past a meter comes from a vessel relieving pressure into the flare header. With known pressures and volumes, vent gas volume can be calculated with precision using conventional gas law procedures.

Section 12-11-602.7 would allow any alternative method if approved by the District and EPA.

EMISSIONS REDUCTIONS

The purpose of Regulation 12, Rule 11, Flare Monitoring at Petroleum Refineries is to gather information on flaring including flow, composition, and cause. The proposed rule does not mandate reductions. Nevertheless, District staff have found that because refiners have looked more closely both at monitoring and the feasibility of flaring reductions, flaring at the five Bay Area refineries has dropped dramatically over the past year. One refinery has installed new compressors that have allowed it to go from flaring an average of 5 million standard cubic feet of vent gas per day to virtually zero routine flaring. The result has been a significant emission reduction that cannot be directly attributed to this rule, but will ultimately be reflected in the emissions inventory.

ECONOMIC IMPACTS

Costs

The proposed rule requires the installation of 3 types of monitoring equipment: (1) flow monitoring equipment, (2) composition monitoring equipment, and (3) video monitoring equipment. Because the rule allows each refinery options, particularly in determining how to monitor vent gas composition, it is difficult to predict cost for each refinery. Cost will also vary because the number of flares at each refinery varies. Costs are divided into two main categories: (1) initial capital and installation costs for equipment, and (2) annual operating and maintenance costs.

Table 5. Capital Cost Items

Cost Item	Cost[1]	Comment
Flow monitor		
Ultrasonic meter w/ installation	$50,000	
Annual amortized cost[2]	**$6164**	
Continuous analyzer (NDIR)		
Hydrocarbon analyzer	$9,000	2 analyzers: (1) dual channel-methane and total hydrocarbon, (2) H_2S
H_2S analyzer	$15,000	
Sample conditioning	$40,000	
AutoCal system	$25,000	
Installation	$50,000	
Total	$139,000	
Annual amortized cost[2]	**$17,137**	
Continuous analyzer (FID)		
Hydrocarbon analyzer	$12,000	2 analyzers: (1) dual channel-methane and total hydrocarbon, (2) H_2S
H_2S analyzer	$15,000	
Sample conditioning	$40,000	
AutoCal system	$25,000	
Installation	$50,000	
Total	$142,000	
Annual amortized cost[2]	**$17,507**	
Continuous analyzer (GC)		
GC	$50,000	
Sample conditioning	$40,000	
Installation	$50,000	
Total	$140,000	
Annual amortized cost[2]	**$17,261**	
Auto-sampling system		
Auto-sampler	$15,000	
Installation	$15,000	
Total	$30,000	
Annual amortized cost[2]	**$3,699**	
Manual sampling station		

Cost Item	Cost[1]	Comment
Installation Annual amortized cost[2]	$10,000 **$1233**	
Video monitoring Equipment w/installation Annual amortized cost[2]	 $5,000 **$616**	

[1] Costs based on vendor estimates or quotes to ARB or District staff
[2] Costs amortized over 10 years @ 4% real interest rate

Table 6. Annual Operating Costs

Cost Item	Cost	Comment
Maintenance for all monitors (per flare)	$20,000	District estimate
Sample analysis	$500/sample	Vendor quote
Report preparation per flare[1]	$4,800	Costs based on 1 day of labor @$50/hr/flare/month

Based on the above cost estimates, the annual cost per flare will depend upon the flare monitoring technologies chosen, but the cost is expected to be about $50,000 per flare. For flares for which composition is monitored by sampling, equipment costs are lower but sample analysis costs bring total cost up to a level comparable to that for flares using continuous analyzers.

At an annual cost of $50,000 per flare, the total cost for the Bay Area refineries together is expected to be about $1.15 million per year. The cost per refinery will depend upon the number of flares at the refinery.

Socioeconomic Impacts

Section 40728.5 of the Health and Safety Code requires an air district to assess the socioeconomic impacts of the adoption, amendment, or repeal of a rule if the rule is one that "will significantly affect air quality or emissions limitations." The proposed rule is intended to provide the tools necessary to analyze refinery flaring. It would impose monitoring requirements for refinery flares but would not impose emission limitations. As a result, these limits cannot be said to "significantly affect air quality or emission limitations," within the meaning of Section 40728.5, and the District will not prepare the socioeconomic analysis that would otherwise be required under Section 40728.5 of the Health and Safety Code. However, the District has attempted to minimize the costs imposed by the proposed rule.

Incremental Costs

Under Health and Safety Code Section 40920.6, the District is required to perform an incremental cost analysis for a proposed rule under certain circumstances. To perform this analysis, the District must (1) identify one or more control options achieving the emission reduction objectives for the proposed rule, (2) determine the cost effectiveness for each option, and (3) calculate the incremental cost effectiveness for each option. To determine incremental costs, the District must "calculate the difference in the dollar costs divided by the difference in the emission reduction potentials between each progressively more stringent potential control option as compared to the next less expensive control option." Because the proposed rule does not impose control requirements, no incremental cost analysis will be prepared.

ENVIRONMENTAL IMPACTS

Pursuant to the California Environmental Quality Act, the District has prepared an initial study for the proposed rule to determine whether rule adoption would result in any significant environmental impacts. The rule is intended to allow the District to collect data on refinery flaring through the imposition of monitoring requirements. Because the rule would not impose emission control requirements, which always have some potential to alter emissions or transfer them from one media to another, and because any necessary construction would take place within existing refineries, no adverse environmental impacts are expected. The study did identify the construction work required to install monitors as a source of potential environmental impacts. However, because of the safety requirements that govern this type of work, the regularity with which similar hot work is conducted in refineries, and the consequent familiarity with and preparedness for this type of work on the part of refinery workers and contractors, the study concluded that the proposed rule would not result in any significant environmental impacts through this mechanism.

REGULATORY IMPACTS

California Health and Safety Code Section 40727.2 require the District to identify existing federal air pollution control requirements for the equipment or source type affected by the proposed rule or regulation. The District must then note any differences between these existing requirements and the requirements imposed by the proposed rule. Table 7 is a matrix of the proposed rule, existing Bay Area regulations, and federal requirements for flares.

Table 7: Comparison of Regulatory Requirements

Agency	Regulation	Control/Performance Requirements	Monitoring Requirements	Emission Limitations
BAAQMD	Reg. 2, Rule 6 (Title V permit)	Specific to facility and source	Specific to facility and source	Throughput limits, visible emission
BAAQMD	Proposed Reg. 12, Rule 11	No	Volumetric flow and composition	No
EPA	40 CFR 60.18 (applies to flares subject to NSPS)	Pilot flame present at all times, heat content, maximum tip velocity, composition	Presence of flame, heating value	Smokeless capacity

Federal Requirements

Federal New Source Performance Standards (NSPS) in 40 CFR Part 60, Subpart A, Section 60.18 apply to flares that are used as general control devices. They specify design and operational criteria for new and modified flares. The requirements include monitoring to ensure that flares are operated and maintained in conformance with their designs. Flares are required to be monitored for the presence of a pilot flame using a thermocouple or equivalent device. Other parameters to be monitored include visible emissions, exit velocity and net heat content of the gas being combusted by the flare.

In addition, the NSPS limit sulfur oxides in vent gases combusted in a flare installed after June 11, 1973 (40 CFR Part 60, Subpart J, Section 60.104). Upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from the standard.

District Requirements

Within the District, a new emission source or a modified existing source must meet the District's New Source Review (NSR) requirements. The NSR program requires the use of Best Available Control Technology (BACT) for new or modified sources that have the potential to emit 10 pounds per day or more of VOC, carbon monoxide, oxides of nitrogen, particulate matter, or sulfur dioxide. For flares, BACT requires a control efficiency of 98% for elevated flares and 98.5% for ground flares. Other permit conditions are imposed on some flares. These conditions may include throughput limits and record keeping to document compliance.

The proposed rule would require continuous monitoring for volume and sampling or the use of continuous analyzers for vent gas composition. Recording of video images of flares would be required. Monthly reports of flow, composition, and other data would be required. For larger releases (over 1.2 million standard cubic feet per day), a report on the time, cause, duration, and reason for the flaring would be required.

RULE DEVELOPMENT HISTORY

The District has been carrying out a complex study of flares and flaring at the Bay Area refineries since January 2002. The study implements further study measure FS-8 from the 2001 Bay Area Ozone Attainment Plan. In the course of the study, District staff have visited all five Bay Area refineries numerous times, have met with refinery staff, ARB and EPA staff, and with community groups in over 50 meetings to discuss issues related to flaring.

A work group was formed to carry out the further study. The workgroup included representatives from California Air Resources Board, Industry, Citizens for a Better Environment, and District Staff. The Environmental Protection Agency and other air districts, including the South Coast AQMD and the San Joaquin Valley Unified APCD participated at various levels throughout the project. The workgroup has met periodically since January 2002 to discuss technical issues. Among those issues have been flare monitoring issues such as flow monitoring and available technologies and composition monitoring methods.

In May 2002, the District conducted an informational public meeting to gather input on the District's plans to implement the commitments in the ozone attainment plan.   In August 2002, District staff held a workshop in Martinez to discuss flare monitoring concepts. At this workshop, community members indicated that they would like to see a rule that required flow monitoring, composition monitoring, reporting requirements, and video monitoring.

Three community meetings were held in March and April..

DISTRICT STAFF IMPACTS

Implementation of the proposed regulation will have a significant impact on the District's resources. However, these changes are essential and necessary in order to satisfy the commitments in the Bay Area 2001 Ozone Attainment Plan.

The proposed regulation will require the installation of monitors. The District will have to exercise oversight for these monitors in a manner similar to that used to oversee continuous emission monitors (CEM). The resources required are similar, and will require District staff to verify the installation of monitoring equipment, conduct accuracy tests or ensure that they are conducted, review monthly reports, perform compliance inspections, and investigate flaring incidents.

Monthly reports on flaring will be required. These reports will have to be reviewed by District staff. The District expects to continue to investigate significant flaring events. This would not represent a change from the model used in the further study measure for flares. A flaring event was defined for the study as any flow over 1,000,000 standard cubic feet per day to a flare. The proposed rule requires an investigation that is included in the monthly report from the refinery whenever daily volume exceeds 1,200,000 standard cubic feet. During the further study period, the time required to investigate events varied, was dependant on the complexity of operations, and ranged from less than an hour to hundreds of hours. This workload will diminish as flaring decreases (as it is currently) and as more data becomes available with new monitors in place.

CONCLUSION

Proposed Regulation 12, Rule 11, Flare Monitoring at Petroleum Refineries, will implement control measure SS-15 from the Bay Area 2001 Ozone Attainment Plan. The rule is intended to gather data on flaring operations at petroleum refineries.

Pursuant to the Health and Safety Code Section 40727, new regulations must meet necessity, authority, clarity, consistency, non-duplicity and reference. The proposed regulation is:

- Necessary to implement control measure SS-15 in the Bay Area 2001 Ozone Attainment Plan;
- Authorized by California Health and Safety Code Section 40702;
- Clear, in that the new regulation specifically delineates the affected industry, compliance options and administrative requirements for industry subject to this rule;
- Consistent with other District rules, and not in conflict with state or federal law;
- Non-duplicative of other statutes, rules or regulations; and
- The proposed regulation properly references the applicable District rules and test methods and does not reference other existing law.

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COMMENTS AND RESPONSES

[to be added]